

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In The Matter Of

PUBLIC UTILITIES COMMISSION.

Instituting a Proceeding to Investigate the Implementation
of Feed-in Tariffs

DOCKET NO. 2008-0273

THE HECO COMPANIES' SUBMISSION OF SUPPLEMENTAL INFORMATION

APPENDICES A-C

AND CERTIFICATE OF SERVICE

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Pursuant to the Commission's April 27, 2009 Order¹ in the above-captioned proceeding, Hawaiian Electric Company, Inc. ("HECO") and its subsidiaries Maui Electric Company, Limited ("MECO") and Hawaii Electric Light Company, Inc. ("HELCO")(collectively, the "HECO Companies"), herein respectfully submit the following information in response to requests made during the panel hearings held from April 13, 2009 through April 17, 2009.² The information provided is also responsive to an informal request received from certain of the

¹ Order Granting The County Of Hawaii's Motion For Approval To Amend Its Status As An Intervenor To A Participant, Filed On April 8, 2009; Granting The City And County Of Honolulu's Motion For Approval To Amend Its Status As An Intervenor To A Participant, Filed On April 8, 2009; Amending Hawaii Holdings, LLC, Doing Business As First Wind Hawaii And Semptra Generation's Status As Intervenors To Participants; And Amending The Schedule In This Proceeding ("Order").

² The HECO Companies have endeavored to provide as much information as possible in response to the requests identified during the panel hearings and also as identified in a document distributed by the Commission on May 7, 2009. To the extent that a comprehensive response was not available at the time of this filing, the HECO Companies will provide the requested information through the Opening Brief which will be filed on May 22, 2009. The HECO Companies also respectfully reserve the right to supplement or modify the information provided to the extent that supplementation or modification will yield a more complete and accurate record upon which the Commission may base its decisions.

intervenor parties in this docket on May 5, 2009.³ The supplemental information is offered for the purpose of providing the Commission with the information and record evidence it requires to make a sound and informed decision in this docket. (See, Order at 9-10)

I. Information Regarding The Number Of Renewable Energy Projects Integrated In The State In The Last Three Years.

During the panel hearing on April 13, 2009, Mr. Hempling requested that the HECO Companies create for the Commission's information an exhibit indicating the number of renewable energy projects integrated into the State by the HECO Companies within the past three years. Mr. Hempling also suggested a possible format for the exhibit. (Transcript of Proceedings ("TR") I-28, line 15 through I-31, line 4). Attached as Appendix A is an exhibit responsive to Mr. Hempling's request.

II. Information Regarding The Specific Costs Associated With Interconnection.

During the panel hearing on April 14, 2009, Mr. Hempling requested the parties to distinguish among the types of costs associated with the interconnection process. (TR II-38, line 5 through II-39, line 13) For the purpose of beginning the discussion regarding the categories of costs associated with the interconnection process with the parties, the HECO Companies preliminarily identify the following interconnection cost categories:

A. Utility System Costs and Upgrades which would include but not necessarily be limited to costs associated with: (1) a new transmission line or infrastructure or upgrades to the

³ The request was received via teleconference on May 5, 2009 from counsel for the Blue Planet Foundation and counsel for Hawaiian Commercial & Sugar Company on behalf of their clients and other intervenor parties. The time for discovery in this proceeding expired on March 4, 2009 and the HECO Companies object to any attempt by any party to unilaterally reopen discovery in contravention of the Commission's January 20, 2009 Order Approving the HECO Companies' Proposed Procedural Order, as Modified. However, without waiving the objection, given the numerous and complex issues present in this proceeding, and the desire to provide the Commission with the information it requires to address those issues, the HECO Companies provide the information below in response to the intervenor parties' request.

existing infrastructure; (2) procurement and installation of equipment which provides ancillary services to mitigate any adverse effects associated with intermittent or variable generation; and (3) relay upgrades, setting changes and protection reviews.

B. Project Specific Equipment which would include but not necessarily be limited to costs associated with: (1) line extensions, substation and transformation equipment and equipment installed at the customer site specifically for the project; (2) SCADA, control system and curtailment system which are specific to the project, allow for system interface and provide control and visibility of the plant to the system operator.

C. Interconnection Review Study costs.

D. Project risk assessment costs, including but not limited to costs associated with curtailment studies.

E. System and feeder studies and technology verification studies performed by the utility.

The HECO Companies will present their proposal for allocation of these costs as between the utility and the developer in their Opening Brief on May 22, 2009.

III. Information Regarding The Status Of The Interconnection Queues For Each Utility.

During the panel hearing on April 16, 2009, Mr. Hempling sought information from the HECO Companies regarding the current generation interconnection queue for each of the three utilities. (TR IV-197, lines 11-14) The attached Appendix B provides the requested information and confirms that none of the HECO Companies has any outstanding request that is not already in process.

IV. Information Regarding General Electric Studies.

During the panel hearing on April 17, 2009, reference was made to a study of the HELCO system by General Electric. (TR V-104, lines 22-25). Additionally and as noted above, on May 5, 2009, counsel representing certain of the intervenor parties requested copies of this General Electric study, and any General Electric Studies completed for HECO and MECO, to the extent those studies are available in the utilities' files.

The increase of intermittent and variable renewable resources could create voltage and frequency regulation, load following, dispatch and unit commitment challenges to the operation of the utility grid. The electrical systems are being analyzed in various studies conducted by General Electric for the utilities. This assessment is being conducted in two phases.

In Phase 1, a detailed electrical and economic model of the existing infrastructure of the grid will be developed using information and models provided by the utility and validated by General Electric, to establish a baseline condition. The transient and production costs models will be validated against utility historical data to achieve confidence in the fidelity of the approach. The main objective of the proposed effort is to develop a baseline model of the electrical infrastructure on the utility grid to serve as a reference point for future scenario analyses exploring different renewable energy and mitigating measure configurations of interest to utility planners. Specifically, the study will develop short-term and longer-term stability models and production cost models to identify the impact on technical performance and operating economics associated with as-available generation on the utility grid. Adequate modeling of the utility grid is an essential first step of the work needed to investigate grid operation with a high content of as-available energy and this effort will assist in addressing this

need. After completing validation of the baseline model, the project will proceed to Phase 2. Phase 2 will analyze the technical and economic impact of infrastructure expansion scenarios (more renewable energy and possible mitigation technologies) relative to the baseline condition.

This analysis is contemplated to provide guidance in determining the amount, if any, of additional intermittent renewable energy generation the systems can reasonably accept without unduly impacting the reliability and operability of the island grids. However, it must be acknowledged that these studies are not meant to be exhaustive in scope and rather are designed in particular to assess any benefits and risks associated with the different mitigating technologies that may be implemented to address issues raised by increasing levels of variable generation on an island system. Accordingly, more in-depth analysis and additional studies will be required in order to determine the extent to which a particular system may be able to integrate a specific project, and to evaluate the particular system requirements associated with such integration.

The Phase 1 studies for both the HELCO and MECO systems have been completed. These Phase 1 studies are voluminous in nature. The HECO Companies are in the process of securing final electronic versions of the documents and will make the studies available to the Commission and Parties via email as soon as the electronic versions are secured. The Phase 1 study for the HECO system is in progress and anticipated to be completed in approximately July of 2009. Preliminary results for model efficacy for the HELCO Phase 2 study are in the review process and it is presently anticipated that a Phase 2 study will be available to the public sometime during the summer of 2009. The MECO Phase 2 study is in progress and anticipated to be completed by year end 2009. The MECO Phase 2 study is confidential and available only to the signatories to an August 21, 2008 settlement agreement and such other persons (inclusive of the Commission and Consumer Advocate) as the signatories shall mutually agree.

V. Information Regarding Load On The Companies' Distribution Feeder Circuits.

The intervenor parties also requested information regarding loading on the Companies' distribution feeder circuits. In particular, the intervenor parties seek information on those circuits which the utilities may already have loading information for as opposed to circuits which the Company will have to physically assess in the field prior to making a determination. While it is possible that the utility may have existing information for certain circuits that information alone would not be sufficient for a developer to independently make an assessment regarding the availability of a particular circuit for a particular project. Accordingly, and as discussed in the context of this proceeding, the most efficient way for a developer to secure project location information relative to a particular circuit is to approach the utility with the specific location (street address), size of the project and type of distributed generation. The Company can then research the circuit that the proposed project would be on and the existing penetration level on that circuit. To the extent that the utility has current and available information on that circuit, that information could assist in expediting the utility's review.

After a preliminary analysis is conducted, the utility can inform the developer whether the proposed project can be accommodated or may require further technical study. The turnaround time on the developer's request will depend upon the number of proposed locations that the developer is requesting information on. It is anticipated that the utility should be able to research approximately five different locations in a one week period. It must be noted that each of the reviews conducted by the utility for the developer represents a "snapshot" in time representing the best information available to the utility at that time. To the extent that the developer sought to pursue the project a significant amount of time after the initial review was done, the developer

would likely have to resubmit its request to the utility to determine if the earlier assessment remains valid due to the dynamic nature of the utility system.

VI. Information Regarding EPRI Reports.

In response to an information request from intervenor party Tawhiri (specifically IR 11, subpart a), the HECO Companies referenced two reports produced by EPRI. On May 5, 2009, counsel for HC&S requested copies of those reports. The HECO Companies have researched the intervenor parties' request and have determined that the reports are in the process of being made available to the public for purchase.

The Electric Power Research Institute, Inc. (EPRI) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies.

EPRI members, such as HECO, receive reports of EPRI's research and development as part of their membership with EPRI. The terms and conditions of EPRI membership prevent members from freely distributing copies of EPRI reports as they are subject to license as well as copyright law. As a nonprofit organization, EPRI has the obligation and does make the reports available to the public, for purchase or otherwise.

In regards to the two subject EPRI reports: (1) *EPRI Evaluation of the Effectiveness of AGC Alterations for Improved Control with Significant Wind Generation* (EPRI Product ID

1018715); and (2) *Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance – Phase 2* (EPRI Product ID 1018716), EPRI is in the process of completing the production of these reports, and they are not yet available to the public. HECO, as a member of EPRI and a funder of the projects in which these reports were developed, has received preliminary draft copies of the reports. The terms and conditions of HECO's membership requires HECO treat these draft reports as confidential information. EPRI will make the final version of the reports available for purchase by the public as soon as production of the reports has been completed.

VII. Information Regarding Electric Power Systems, Inc. Report

In response to an information request from Tawhiri (specifically IR 11, subpart e), the HECO Companies referenced a report produced by Electric Power Systems, Inc. concerning a December 29, 2006 HELCO wind integration impact study. On May 5, 2009, counsel for HC&S requested a copy of this report. The report is attached as Appendix C and provides important information regarding the issues associated with integrating intermittent renewable resources on an island grid.

Dated: Honolulu, Hawaii, May 8, 2009.



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**Exhibit 1 - Renewable Energy Projects
2006 - 2008**

Name	Prime Mover [Primary Fuel]	Contract Date	Expected In-Service Date	Actual In-Service Date	Contract Capacity MW [Firm Cap Rate]
HECO					
Hoku Solar, Inc. --Owner/Operator; HECO Archer Substation PV Plant	Photovoltaic [Solar]	November 2007	Decemeber 2008	Pending (target is June 2009)	Allowed 0.3 (DG)
MECO					
Makila Hydro, LLC	Hydro Turb [Water]	May 2005	September 2006	September 2006	Allowed 0.5
Kaheawa Wind Power, LLC --Owner; UPC Wind Management, LLC -- Operator; Kaheawa Wind Farm --Facility	Wind Turb (twenty 1.5 MW) [Wind]	December 2004	June 2006	June 2006	Allowed 30
Lanai Sustainability Research, LLC	Photovoltaic (twelve 100 kWac) [Solar]	August 2008	December 2008	December 2008	Allowed Capacity shall be lower of 1.2 or net nameplate capacity (net for export) by In-Service Date.
HELCO					
Tawhiri Power LLC (wholly owned subsidiary of Apollo Energy Corporation) --Owner/Operator (former owners: Kamaoa Wind Energy Partners; Kamakani Ikaika); Pakini Nui Wind Farm --Facility (formerly Kamao'a Wind Farm)	Wind Turb (fourteen 1.5 MW: Group A --7.5 MW; Group B-- 13.5 MW) [Wind]	April 1985 (Group A) October 2004 (Group B)	March 2007	April 2007	Allowed 20.5 (Group A--7.0; Group B--13.5)
Department of Water Supply [DWS], County of Hawaii --Operator; Kaloko Tank 2 --Facility	Hydro Turb [Water]	May 2007	June 2008	June 2008	Allowed (lower of 50 kW or installed and operating capacity six months after Operational Date.)
Hawi Renewable Development, Inc. [HRD] --Owner/Operator; Hawi Wind Farm --Facility	Wind Turb [Wind] (sixteen .660 MW)	May 2006 to at least May 2021 (minimum 15)	May 2006	May 2006	Allowed 10.56
Keahole Solar Power LLC -- Owner/Operator	Compressed CO2 Engine (two 250 kW) [Solar]	September 2008 to at least 10 Contract Years following Commercial Operation Date	Guaranteed Commercial Operation Date of December 31, 2008.	Pending (target is June 30, 2009)	Allowed Capacity shall be lower of 500 kW or net nameplate capacity (net for export) by In- Service Date.

Interconnection Queue Status

Exhibit A &						
Customer	Developer	Capacity (kW)	Initial Contact	Diagrams Received	Technical	
					Review Completed	Review Status
HECO						
Customer 1	DRI	135	2/21/2008	11/3/2008	12/12/2008	completed
Customer 2	DRI	135	2/21/2008	11/3/2008	12/12/2008	completed
Customer 3	SunPower	225	10/17/2008	11/7/2008	12/12/2008	completed
MECO						
Customer 1	ECM	15	1/8/2008	1/12/2009	1/27/2009	completed
Customer 2	ProVision Technologies	135	4/17/2008	5/13/2008	5/27/2008	completed
Customer 3	Hoku Solar	262	10/14/2008	11/21/2008	12/5/2008	completed
Customer 4	SunPower	139	10/30/2008	10/30/2008	12/10/2008	completed
Customer 5	Ron Ho		3/19/2009			waiting for customer to provide additional information
HELCO						
Customer 1	SunPower	300	1/9/2008	10/7/2008	12/1/2008	completed
Customer 2	SunPower	600	10/15/2008	10/15/2008		consultant working on study
Customer 3	Suntech	100	11/14/2008	11/14/2008	12/1/2008	completed
Customer 4	Suntech	135	3/18/2008	12/11/2008	12/19/2008	completed
Customer 5	Ron Ho	135	11/6/2008	11/6/2008	4/22/2009	completed
Customer 6	Suntech	135	10/20/2008	12/8/2008	12/11/2008	completed



Hawaiian Electric Light Company
Wind Generation
Impact Study – Phase II
December 29, 2006

Prepared by:
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1 Background

Hawaii Electric Light Company ("HELCO") is currently experiencing an increase in wind generation construction and applications for interconnection to its system. In 2005, HELCO contracted with Electric Power Systems, Inc ("EPS") to complete a preliminary impact study on the combined impacts of non-traditional generation resources on the HELCO system. As a result of that study, HELCO has selected EPS to provide a follow-up report on the impacts of additional wind generation on the HELCO system with particular emphasis on reliability, load shedding and spinning reserve impacts.

EPS has worked with the HELCO staff to develop both typical and atypical system conditions to develop a more complete understanding of the impacts of extensive wind penetration in the HELCO system. The study was not undertaken in an effort to provide support to either increase or decrease the amount of wind generation on the HELCO system, but to more fully understand the impacts of additional wind generation on the system from a transient stability perspective. Known steady-state interactions with AGC or dynamic stability problems associated with wind generation are beyond the scope of this study. These items, such as AGC and wind interaction can create both long-term and dynamic stability problems that are best addressed by other than transient stability analysis.

Of primary concern for the HELCO system was the adequacy of the existing underfrequency load shedding system and the impact increased wind penetration will have on its performance and ability to limit uncontrolled or cascading outages.

The ability to maintain system stability following transient conditions such as typical line faults was also evaluated as wind penetration is increased, displacing more traditional resources such as steam units.

The main source of power in the HELCO system is currently derived from fossil fuel power plants, typical of most islanded electrical systems. This reliance on fossil fuel tends to result in more expensive energy than may otherwise be available to utility systems in the continental US. This high energy cost increases the attractiveness of alternative energy systems such as wind power. Interconnected power systems on the mainland or large islanded systems can promote the use of wind power with little concern for their impact on system operations. In these large interconnected systems, the amount of generation migration to these resources in the power system is very small when compared to the overall electrical system generation resources.

Wind farms on isolated systems generally degrade the reliability and robustness of islanded power systems by replacing larger inertia machines that have predictable and controllable output power with wind generators with little inertia, erratic output, and limited short circuit capacity.

2 Executive Summary

The completion of the HRD (10 MW) and the Apollo (20 MW) wind farms will have an impact on the reliability, spinning reserve requirements, and robustness of the HELCO system. Should HELCO elect to cycle large steam units either daily or seasonally, this impact is amplified to unacceptable levels in certain cases.

In the HELCO system during peak loading conditions, additional wind power results in less stable steady-state frequency control during normal operation. The frequency control is degraded due to the variability of wind power over time and the requirement for thermal generation to "chase" the output of wind generation. However, this degradation does not appear unacceptable nor does it result in unstable operation so long as adequate steam generation remains on-line. However, this

frequency control analysis does not include the wind/AGC interactions which will be considerably worse than our simulations.

When wind power is utilized to displace steam generation in conjunction with LM 2500 turbines, fluctuations in wind power appear to excite the natural response mode of the LM 2500s, resulting in frequency oscillations during normal operation. In off-peak load levels, wind must be curtailed in order to maintain adequate steam units on-line and maintain system stability.

As the amount of wind generation is increased, spinning reserve requirements must increase over historic levels using traditional generation resources due to the variability in wind power. In the extreme case, spinning reserves equal to the actual power output of the wind farms may be required to avoid load shedding following the rapid decay of wind. Unfortunately, the exact impact of wind penetration on frequency regulation cannot be predicted with transient stability simulations. Transient stability simulations can predict the response of the system to changes in output power caused by changes in wind, but cannot predict the variability of the wind itself. The exact impact on system frequency control can only be determined by measuring historic trends in actual output power of the wind farms. The complex interaction between normal load changes, random wind energy changes and AGC control will result in a less stable "steady-state" frequency control in islanded systems.

Under peak loading conditions, system stability and robustness is not changed appreciably by adding 30 MW of wind power. For the same contingencies, increased wind generation will not result in any more load shedding but will create slightly larger oscillations in system frequency. As the load decreases, the impact of wind becomes more apparent, resulting in unacceptable reliability and response characteristics.

System stability and robustness degrades rapidly as the ratio of wind and LM 2500 to steam-driven generation increases. In the extreme case of maximum wind generation with minimum steam generation, the system suffers a total collapse for many fairly routine system contingencies such as loss of a single thermal generator. Some transmission line faults are also severely impacted by the loss of steam generation, with certain faults creating system instability with increased wind generation.

The key to stability in the HELCO system is directly related to the number of steam driven generators operating on the system. As steam generation is displaced by wind generation or aero derivative turbines (LM 2500s), system stability and robustness decrease dramatically. If the steam units are replaced with LM 2500s and wind power or only one steam unit is operating, the loss of a single generator results in either undamped or poorly damped oscillations with frequency swings varying over +/- 1.5 Hz, or in complete blackouts. As loads decrease from peak values and other steam units are removed from service, the system becomes considerably less stable and prone to oscillations and instability following disturbances. During cases where minimal steam or no steam generators are in service, the system collapses for numerous contingencies such as generator trips and some line faults.

During minimum load conditions, unconstrained wind generation of up to 30 MW reduces the number of steam units that can remain on-line and results in instability for simple generator trips and line faults. This instability would separate the system into multiple islands and result in partial or complete system outages.

From simulations completed as part of this study, it would appear that the HELCO system is fairly robust and stable for generation trips, when operated under historical conditions. This stability margin decreases rapidly as steam units are replaced by wind generation or taken off-line for maintenance. The system appears to be fairly robust for transmission line faults under most

dispatch scenarios, with certain combinations of wind and LM 2500 generation resulting in unstable response.

The practice of operating a Keahole LM 2500 unit when loads increase above 130 MW appears prudent under traditional dispatch scenarios. During these conditions, faults on the 9100 line will result in stable oscillations of this unit. As steam units are displaced, oscillations created by faults on the 9100, 7700, 8500 and 8800 lines increase in magnitude. Certain faults become unstable over time. Other faults initiate considerable oscillations, but appear to be eventually stable.

The existing HELCO load shedding scheme appears to minimize the loss of customer load during an underfrequency event. This type of scheme is common in the mainland, but has severe drawbacks in islanded systems. The system appears susceptible to under shedding the required load in abnormal or off-peak conditions, placing the system at risk of total collapse without extremely fast manual intervention. The scheme creates an increased risk to the entire system or operating generators following the loss of single or multiple generators. EPS recommends the load shedding scheme be more tailored to islanded power systems. A proposed load shedding scheme is included within this report.

Sensitivity studies indicate that increased wind and LM 2500 generation results in a system that is extremely sensitive to under-shedding or over-shedding following the trip of on-line generation.

Operating the system with less than two large steam turbines on-line places the system at considerable risk of collapse following many contingencies. Although wind generation appears to be more adverse than LM 2500 generation, the displacement of steam generation by either one degrades the system reliability. Substitution of one or two smaller steam unit(s) in lieu of one large steam unit may be possible but was not evaluated in this study.

3 Summary of Recommendations

Based on the results of this impact study, the following is a summary of recommendations.

1) Minimum Steam Generation

The HELCO system is extremely sensitive to the number of steam units operated on the system. As the number of steam units is reduced, system stability decreases along with the increased risk of large scale outages and equipment damage due to system swings. We recommend the system not be operated with less than 2 steam units on-line during any load level.

It is unknown if the Shipman units can be substituted for one of the larger steam units for this constraint.

2) New Load Shedding Schedule

EPS recommends HELCO implement a new load shedding schedule similar to the one included within this report. The total amount of load under automatic load control should be no less than 70-80% of the system load.

3) Selection of Load Shedding Feeders

HELCO should select feeders for the first and second stages of load shedding whose load levels approximately scale in proportion to the total system load to avoid unbalanced load shedding at various system load levels. This load can be rotated between feeders in the system with the exception of the few feeders whose valley and peak loads do not follow the same trend as the system and valley peak loads. These few feeders should be reserved for use only stage 3 or 4 of the proposed system.

4) Keahole Unit Operation

The operation of the Keahole units for load levels above 130 MW appears prudent considering the risk of voltage collapse for several contingency cases. However, several contingencies result in oscillatory behavior of the Keahole LM 2500 unit or units following line faults if there are less than two steam units on-line in the HELCO system at the time of the fault. The impact of using CT-2 instead of a LM-2500 for this support should be investigated.

5) Spinning Reserve

The addition of wind energy on the HELCO system required an additional kicker block be added to the underfrequency schedule. This kicker block is considerably higher in frequency than historic schedules. To avoid shedding this block of consumers due to frequency deviations caused by fluctuations in wind energy and its dynamic interaction with AGC, HELCO should increase its spinning reserve levels over historic values. The exact value should be determined following operating experience of the wind energy. In the initial start-up, we recommend the minimum level of spinning reserve be increased over HELCO's historic levels by an amount that is at least equal to the firm load level of the kicker block of underfrequency loadshedding (4-6 MW). Although this increase in spinning reserve will increase operating costs over historic levels, it is required to maintain comparable reliability to the pre-wind system conditions.

6) New Generation Impacts

As new generation is evaluated for the HELCO system, the generation's impact on the system's operating characteristics over a wide range of load levels and dispatch scenarios should be evaluated. The studies should evaluate the impact on transient stability concerns for transmission line fault conditions and also unit trip contingencies.

7) System Recorders

HELCO should continue with its installation of dynamic system recorders at key locations on its system. HELCO should also continue to gather information on the response characteristics and machine dynamics of its generation units, in particular its older steam units. These units are critical to the stability of the HELCO system and their characteristics should be confirmed for use in future studies.

4 Power Flow & Stability Model

EPS utilized the power flow and stability model originally provided by Hawaii Electric Company ("HECO") to evaluate the power flow and transient stability impacts of DG/AE on the HELCO system, during the first phase of this study. In this study, the PSS/E database was reviewed and modified to reflect the actual machine and governor data provided by HELCO personnel.

EPS reviewed all of the steady-state and dynamics data in the database and compared it with either documentation supplied by HELCO or with the best available approximation from similar machines in those cases where documentation was not available. HELCO provided documentation for the following units: Hill 5, Hill 6, Shipman 3 & 4, Puna steam, CT2, CT3, CT4, CT5, PGV, and HEP. Detailed generator data was available for most units, some exciter data was available, and only a small amount of turbine / governor data was available. When possible, SCADA records were reviewed to help quantify the ability of the units to respond to transient conditions. In order to better quantify the response, transient recordings much faster than the SCADA snapshots are required. Absent these records, EPS attempted to utilize the available SCADA records and model the transient characteristics of the various plants based on discussion with HELCO personnel and the unit's known mechanical and control characteristics.

EPS utilized data provided by HELCO in developing detailed models of the LM-2500 series of turbines on the HELCO system, including HEP CT1 and CT2, Puna CT3, and Keahole CT4 and CT5. The impact of these units in conjunction with increased wind penetration is of particular concern in islanded power systems.

The HEP DCS system acts as a single-plant AGC system, providing control of the three units located at HEP to maintain constant power flow interchange with HELCO. This type of control system is common between IPPs and utilities in large interconnected systems, but is discouraged in islanded or weakly interconnected systems. The DCS controller may lead to thermal overload on certain transmission lines in some contingency conditions.

All of the LM 2500 units were reviewed for inertia data and governor control characteristics in the dynamics database. The normalized inertia constants for the units supplied by HECO appear to be correct and required only minor adjustments. However, the gas turbine time constants for each of the LM 2500 units appear to be in error. The time constants within PSS/E appear to be time constants for single-shaft gas turbines, such as a GE Frame 5 turbine. The LM 2500 time constants were changed to approximately 1.5 seconds based on documentation and testing at similar units.

This time constant reflects the time it takes for a step change in the movement of the gas valve to be seen as a step-change in the mechanical output power as measured at the shaft of the power turbine stage of the LM2500. In aero-derivative engines, the time delay between the exhaust gas leaving the first stage compressor and the gas creating the mechanical power on the turbine shaft is an additional time delay not present in single-shaft turbines. The use of the faster time constants found in single-shaft turbines would present a much more stable turbine response than is available from the LM 2500 found in the HELCO system.

The combination of light inertia and increased time constants has a dramatic impact on the stability of the LM 2500 units during transient events. The correction of the unit's time constant illustrates stability problems in several cases where previous simulations did not predict stability problems.

The second major change associated with unit parameters was the correction of unit droop parameters in the database. EPS changed the machine droops for each of the HELCO units based on documentation received from HELCO personnel to match actual conditions in the field. We did not attempt to model governor linkage, soft hydraulics or other items that may be included in some of the older governors and fuel controllers.

Table 1 below lists the original and revised droop constants for each of the machines.

Table 1 – Machine Droop Characteristics

	PSS/E				Original Database Value	New Value
	Bus #	Bus Name	ID	Base (MVA)	Droop (%)	Droop (%)
UNIT						
Hill Unit No. 6 (steam)	5306	KANO H6	6	27.50	6.0%	4.0%
Hill Unit No. 5 (steam)	5305	KANO H5	5	15.63	5.6%	4.0%
Puna Steam Plant (steam)	5600	PUNA	1	18.75	6.0%	4.0%
Shipman Unit No. 3 (steam)	5370	SHIPMANB	3	9.38	6.7%	4.0%
Shipman Unit No. 4 (steam)	5370	SHIPMANB	4	9.38	6.7%	4.0%
Waimea D-12 (emd diesel)	2800	WAIMEA	2	3.44	6.4%	4.0%
Waimea D-13 (emd diesel)	2800	WAIMEA	3	3.44	6.4%	4.0%
Waimea D-14 (emd diesel)	2800	WAIMEA	4	3.44	6.4%	4.0%
Kanoelehua D-11 (fairbank morris dsl)	1330	KANO HSD	1	2.75	no model	
Kanoelehua D-15 (emd diesel)	2330	KANO HSD	5	3.44	6.4%	4.0%
Kanoelehua D-16 (emd diesel)	2330	KANO HSD	6	3.44	6.4%	4.0%
Kanoelehua D-17 (emd diesel)	2330	KANO HSD	7	3.44	6.4%	4.0%
Keahole D-21 (emd diesel)	2402	KEAH HSD	1	3.44	6.4%	4.0%
Keahole D-22 (emd diesel)	2402	KEAH HSD	2	3.44	6.4%	4.0%
Keahole D-23 (emd diesel)	2402	KEAH HSD	3	3.44	6.4%	4.0%
Panaewa D-24 (cummins diesel)					no model	
Ouli D-25 (cummins diesel)					no model	
Punaluu D-26 (cummins diesel)					no model	
Kapua D-27 (cummins diesel)					no model	
Kanoelehua CT-1 (gas turb, frame 5)	5301	KANO CT1	1	13.53	no model	
Keahole CT-2 (gas turb, solar)	5402	KEAH CT2	2	22.20	6.3%	4.0%
Puna CT-3 (gas turb, 1m2500)	5603	PUNA CT3	3	29.60	6.3%	4.0%
Keahole CT-4 (gas turb, 1m2500)	5404	KEAH A	4	25.23	6.3%	4.0%
Keahole CT-5						
Keahole CT-5 (gas turb, 1m2500)	5405	KEAH B	5	25.23	6.3%	4.0%
FIRM POWER IPP						
PGV (geothermal)	5501	PGV	1	21.88	no governor	
	5502	PGV	2	21.88	no governor	
HEP 1 UNIT SC (1 1m2500)	5900	EDC A	1	35.41	8.0%	4.0%
HEP 2 UNIT SC (1 1m2500)	5900	EDC A	2	35.41	8.0%	4.0%
HEP Steam	5900	EDC A	3	23.53	8.0%	4.0%
AS-AVAILABLE POWER						
HYDRO						
Waiau 350 KW Unit	1220	WAIAU	1	0.38	no governor	
Waiau 750 KW Unit	1220	WAIAU	2	0.75	no governor	
Puueo 750 KW Unit	1200	PUUEO	3	0.75	no governor	
Puueo new Unit	1200	PUUEO	4	3.00	no governor	
Wailuluku (IPP)	2171	WRHPC	1	6.12	no governor	
	2171	WRHPC	2	6.12	no governor	
Wind						
Lalamilo Wind Farm	8680	LALAMILO	1	4.00	n/a	n/a
Kamaoa Wind Farm (IPP)	5020	KAMAOAL	1	9.25	n/a	n/a
HRD (IPP)	96860	HRD	1	11.67	n/a	n/a
Apollo (replaces Kamaoa) (IPP)	95000	APOLLO	1	23.34	n/a	n/a

One other major change to the database was the tripping time associated with underfrequency relays. This change does not reflect an error in the database, but a change in the database to reflect the proposed loadshedding schedule.

The existing database utilizes breaker operating times of 0.117 seconds (7 cycles) and relay operating times of 0.2 seconds (12 cycles) for underfrequency protection. These times are acceptable in the historic generation dispatch, however, these long times lead to instability and severe oscillations as traditional steam units are replaced by LM 2500s or wind generation.

The existing HELCO database contains load shedding relay settings with frequency pickup points staggered from 59.0 Hz to 57.8 Hz in 0.2 Hz increments, with relay time delays of 0.2 seconds (12 cycles) in addition to the breaker tripping delays. There are also relays with long time delay settings of 2.5 to 10.0 seconds at 58.5 Hz, and instantaneous relays at 57.0 Hz.

To accommodate the new loadshedding scheme, the breaker's operating times were changed to 0.083 seconds (5 cycles) and relay operating times were assumed to be capable of operating as fast as 0.050 seconds (3 cycles). The total time delay associated with distribution breakers operating for an underfrequency condition was assumed to be 0.133 seconds (8 cycles). This time is critical for the first and second stages of load shedding, but less critical for stages three and four. Feeders with breaker/relay times greater than 0.133 seconds (8 cycles) should be utilized on only the 3rd and 4th stages of load shedding. Although each relay time delay and each breaker tripping time in the HELCO database was modeled identically, in actual practice each relay's intentional time delay will be identical, but the total clearing time will vary slightly due to the actual tripping time of different feeder breakers. For instance, relays that trip a 5 cycle breaker should be set with a total intentional time delay of 3 cycles. Relays that trip a 3 cycles should also be set with a total intentional time delay of 3 cycles, even though this will result in a total tripping time of only 6 cycles.

EPS modeled the existing load shedding set-points and proposed new set-points for the HELCO system based on transient stability simulations. All of these changes have been reflected in the PSS/E database.

4.1 Power Flow Models

In an attempt to identify the impact of wind generation of the HELCO system, EPS developed several power flow and dispatch scenarios to evaluate the impact of wind and non-steam generation at various load levels. These power flows were developed to evaluate the system response under four different loading conditions. When developing an underfrequency loadshedding scheme, it is important to evaluate the scheme for many different system loads and dispatch scenarios. For instance, a loadshedding schedule developed to only cover the peak loading scenario may not provide the protection required at off-peak conditions. For example, the existing underfrequency condition controls enough load at peak value to cover the loss of the HEP plant, however at off-peak conditions, the system is deficient and will result in either extremely low underfrequency operation or system collapse. Neither condition is acceptable.

In selecting the dispatch scenarios to serve each load level, we attempted to define the boundary cases for the cases. For instance, it is doubtful the system will be operated without steam turbines on-line, however if a loadshedding scheme can be designed to protect the system in this scenario, then the scheme will also provide protection under less stressful conditions. It is also important to consider that performing system planning studies is considerably different than actual operation. Although a system may not be planned to operate in a particular condition, maintenance schedules, unscheduled outages etc may result in operating conditions considerably different than planning conditions.

For all cases described below, PGV generation was on-line at its contract limits. The power flows are described in more detail as follows:

4.1.1 Valley Load Cases

These cases represent the minimum load level (89 MW) of the HELCO system as recorded on the utility SCADA system. Two power flow cases were created, (valley-1) where the generators were historically dispatched by HELCO in the actual valley load case, and (valley-2) a second case removing all steam generation and dispatching maximum HEP and wind generation. Although it may not be probable that all steam generation would be removed from the system, this represents the boundary case for these operating studies. The valley dispatch cases are shown in table 2 below:

Table 2 – Generation Summary – Minimum Load Cases

UNIT	From AGC Unit MW Limits				2006 Minimum Load Case (valley-1)			Min Load, Wind (valley-2)		
	Max	Current	LFC	ECO		Current Cap	LFC		Current Cap	LFC
	Cap (MW)	Cap (MW)	Max (MW)	Max (MW)	Pgen (MW)	SpIn (MW)	SpIn (MW)	Pgen (MW)	SpIn (MW)	SpIn (MW)
Hill Unit No. 6 (steam)	25.00	23.00	20.30	20.30	17.80	5.20	2.50			
Hill Unit No. 5 (steam)	14.00	13.70	13.50	13.50						
Puna Steam Plant (steam)	16.00	16.00	14.10	14.10	9.40	6.60	4.70			
FIRM POWER IPP										
PGV (geothermal)	15.50	13.00	13.00	13.00	12.30			12.00		
	15.50	13.00	13.00	13.00	14.90			15.00		
HEP 2 UNITS CC (2 1m2500 + 1 Steam)	22.00	22.00	20.80	20.80	17.80	4.20	3.00	20.00	2.00	0.80
HEP 1 UNIT CC (1 1m2500 + 1 steam)	22.00	22.00	20.80	20.80						
HEP 2 UNITS SC (2 1m2500)	17.50							10.00	0.00	0.00
HEP 1 UNIT SC (1 1m2500)										
AS-AVAILABLE POWER										
HYDRO										
Wailuluku (IPP)	6.00	6.00	6.00	6.00	5.40			5.00		
Wind	6.00	6.00	6.00	6.00	5.40					
Lalamilo Wind Farm	1.50									
Kamaoa Wind Farm (IPP)	9.00									
HRD (IPP)	11.00				2.40			10.00		
Apollo (replaces Kamaoa) (IPP)	21.00							20.00		
					89.15	16.00	10.20	92.00	2.00	0.80

4.1.2 125 MW Load Cases

These cases represent the HELCO system at a system loading of 125 MW. The load level of 125 MW was selected because it is slightly below the 130 MW load level where additional generation is placed on-line for stability and voltage support, primarily on the western side of the system. The 125 MW load level was created by scaling the actual valley loads up to 125 MW. For this load, four power flows were created, (125-1) for the "normal" or historical generation dispatch, (125-2) a dispatch scenario using no wind, but substituting an LM 2500 generator for a steam generator, (125-3) a case with steam generation and maximum wind generation of 30 MW, and (125-4) a case with maximum LM 2500 generation and unconstrained wind generation, removing the sole steam unit on the system.

These cases were selected to provide both boundary conditions and sensitivity analysis of the system to changes in steam generation. The dispatch scenarios provide insight into how the robustness of the system changes with changes in generator units. The 125 MW dispatch cases are shown in table 3 below:

Table 3 – Generation Summary – 125 MW Load Cases

UNIT	125 MW Load, Normal (125-1)			125 MW Load, All CT Spin (125-2)			125 MW Load, Wind (125-3)			125 MW Load, All CT Spin (125-4)		
	Pgen	Current Cap	LFC	Pgen	Current Cap	LFC	Pgen	Current Cap	LFC	Pgen	Current Cap	LFC
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Hill Unit No. 6 (steam)	15.00	8.00	5.30	20.30	2.70	0.00						
Hill Unit No. 5 (steam)							13.50	0.20	0.00			
Puna Steam Plant (steam)	13.00	3.00	1.10				13.50	2.50	0.60			
Puna CT-3 (gas turb, 1m2500)				12.70	7.10	6.50				13.10	6.70	6.10
PGV (geothermal)	12.00			12.00			12.00			12.00		
	15.00			15.00			15.00			15.00		
HEP 2 UNITS CC (2 1m2500 + 1 Steam)	21.50	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00
HEP 1 UNIT CC (1 1m2500 + 1 steam)	21.50	0.50	0.00	21.50	0.50	0.00				21.50	0.50	0.00
HEP 2 UNITS SC (2 1m2500)	17.00	0.00	0.00	17.00	0.00	0.00	8.50	0.00	0.00	17.00	0.00	0.00
AS-AVAILABLE POWER												
HYDRO												
Waiau 350 KW Unit	0.30			0.30			0.30			0.30		
Waiau 750 KW Unit	0.50			0.50			0.50			0.50		
Puueo 750 KW Unit												
Puueo new Unit	2.00			2.00			3.00			2.00		
Wailuluku (IPP)	3.60			2.20			3.60			2.20		
Wind	3.60						3.60					
Lalamilo Wind Farm												
Kamaea Wind Farm (IPP)												
HRD (IPP)							10.00					
Apollo (replaces Kamaea) (IPP)							20.00			20.00		
	125.00	12.00	6.40	125.00	10.80	6.50	125.00	3.20	0.60	125.10	7.70	6.10

4.1.3 160 MW Load Cases

These cases represent the HELCO system at a system load of 160 MW. The case was selected as being representative of the HELCO system at an off-peak condition. The load distribution was created by scaling the loads in the HELCO peak case down to 160 MW. Three power flow cases were created, (160-1) for the "normal" or historical generation dispatch, (160-2) a dispatch scenario using 30 MW of wind and one steam generator, and (160-3) a case with no steam generation, maximum wind generation of 30 MW and maximum LM 2500 generation. The 160 MW dispatch cases are shown in table 4 below:

Table 4 – Generation Summary – 160 MW Load Cases

UNIT	From AGC Unit MW Limits				160 MW Load, Normal (160-1)			160 MW Load, Wind (160-2)			160 MW Load, Min Steam, Max LM2500 (160-3)		
	Max	Current	LFC	ECO		Current	LFC		Current	LFC		Current	LFC
	Cap (MW)	Cap (MW)	Max (MW)	Max (MW)	Pgen (MW)	Cap (MW)	Spin (MW)	Pgen (MW)	Cap (MW)	Spin (MW)	Pgen (MW)	Cap (MW)	Spin (MW)
Hill Unit No. 6 (steam)	25.00	23.00	20.30	20.30	18.00	5.00	2.30	17.40	5.60	2.90			
Hill Unit No. 5 (steam)	14.00	13.70	13.50	13.50	10.50	3.20	3.00						
Puna Steam Plant (steam)	16.00	16.00	14.10	14.10	13.00	3.00	1.10						
Keahole CT-4 (gas turb, lm2500)	22.79	19.50	19.00	19.00							16.00	3.50	3.00
Keahole CT-5 (gas turb, lm2500)	22.79	21.00	20.50	20.50	20.50	0.50	0.00	17.00	4.00	3.50	17.10	3.90	3.40
FIRM POWER IPP													
PGV (geothermal)	15.50	13.00	13.00	13.00	12.00			12.00			12.00		
	15.50	13.00	13.00	13.00	15.00			15.00			15.00		
HEP 2 UNITS CC (2 lm2500 + 1 Steam)	22.00	22.00	20.80	20.80	21.50	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00
HEP 1 UNIT CC (1 lm2500 + 1 steam)	22.00	22.00	20.80	20.80	21.50	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00
HEP 2 UNITS SC (2 lm2500)	17.50				17.00	0.00	0.00	17.00	0.00	0.00	17.00	0.00	0.00
AS-AVAILABLE POWER													
HYDRO													
Waiau 350 KW Unit	0.35	0.35	0.35	0.35	0.30			0.30			0.30		
Waiau 750 KW Unit	0.80	0.75	0.75	0.75	0.50			0.50			0.50		
Puueo 750 KW Unit	0.75	0.75	0.75	0.75									
Puueo new Unit	3.05	2.70	2.40	2.40	3.00			3.00			3.00		
Wailuluku (IPP)	6.00	6.00	6.00	6.00	3.60			4.80			3.00		
Wind	6.00	6.00	6.00	6.00	3.60						3.10		
Lalamilo Wind Farm	1.50												
Kamoa Wind Farm (IPP)	9.00												
HRD (IPP)	11.00							10.00			10.00		
Apollo (replaces Kamoa) (IPP)	21.00							20.00			20.00		
					160.00	12.70	6.40	160.00	10.60	6.40	160.00	8.40	6.40

4.1.4 Peak Cases

These cases represent the HELCO system at a system peak of 192 MW. The load was selected from the historic peak load condition on December 19, 2005. Four power flows were created, (peak-1) for the "normal" or historical generation dispatch, (peak-2) a dispatch scenario using 30 MW of wind to replace one small steam generator and two small diesel units, (peak-3) a case where Puna steam was replaced with LM 2500 units, and (peak-4) a case with maximum wind generation of 30 MW and maximum LM 2500 generation, resulting in only one steam unit on-line (Hill 5).

The selection of the system dispatch may not reflect actual operating practices, but was designed to provide insight into the robustness of the HELCO system under different dispatch scenarios and to define the boundary conditions for acceptable operating parameters. The peak MW dispatch cases are shown in table 3 below:

Table 5 – Generation Summary – Peak Load Cases

	2005 Peak Load Case (peak-1)			2005 Peak, Wind (peak-2)			2005 Peak, Min Steam, Max LM2500 (peak-3)			2005 Peak, Min Steam, Max LM2500, Wind (peak-4)		
		Current Cap	LFC		Current Cap	LFC		Current Cap	LFC		Current Cap	LFC
UNIT	Pgen (MW)	Spin (MW)	Spin (MW)	Pgen (MW)	Spin (MW)	Spin (MW)	Pgen (MW)	Spin (MW)	Spin (MW)	Pgen (MW)	Spin (MW)	Spin (MW)
Hill Unit No. 6 (steam)	15.81	7.19	4.49	14.90	8.10	5.40	20.00	3.00	0.30			
Hill Unit No. 5 (steam)	13.47	0.23	0.03	13.00	0.70	0.50	13.00	0.70	0.50	13.00	0.70	0.50
Puna Steam Plant (steam)	14.02	1.98	0.08	14.00	2.00	0.10						
Shipman Unit No. 3 (steam)	6.44	0.76	0.36	5.80	1.40	1.00	6.00	1.20	0.80			
Shipman Unit No. 4 (steam)	6.07	1.13	0.33									
Keahole D-21 (emd diesel)	1.48	1.22	1.02	2.50	0.20	0.00	2.50	0.20	0.00			
Keahole D-22 (emd diesel)	2.10	0.40	0.40				2.50	0.00	0.00			
Keahole D-23 (emd diesel)	2.44	0.31	0.06									
Puna CT-3 (gas turb, lm2500)	20.45	0.00	0.00				16.00	3.80	3.20	16.00	3.80	3.20
Keahole CT-4 (gas turb, lm2500)	18.51	0.99	0.49	18.51	0.99	0.49	16.00	3.50	3.00	17.00	2.50	2.00
Keahole CT-5 (gas turb, lm2500)							20.00	1.00	0.50	20.00	1.00	0.50
FIRM POWER IPP												
PGV (geothermal)	15.02			15.02			15.00			15.00		
	15.53			15.53			15.00			15.00		
HEP 2 UNITS CC (2 lm2500 + 1 Steam)	21.5	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00
HEP 1 UNIT CC (1 lm2500 + 1 steam)	21.5	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00	21.50	0.50	0.00
HEP 2 UNITS SC (2 lm2500)	17.22	0.00	0.00	17.22	0.00	0.00	17.00	0.00	0.00	17.00	0.00	0.00
AS-AVAILABLE POWER												
HYDRO												
Wailuku (IPP)	0.57			2.00			3.00			3.00		
Wind												
HRD (IPP)				10.00						10.00		
Apollo (replaces Kamaea) (IPP)				20.00						20.00		
	192.13	15.21	7.26	191.48	14.39	7.49	192.00	14.40	8.30	192.00	9.00	6.20

5 Transient Stability Simulations – Unit Trip Conditions

During normal operation of the power system, the amount of power produced by generators is equal to the amount of power consumed by consumers plus system losses. At steady state, generation is constantly adjusted to maintain this balance and keep frequency at 60 Hz. When a generator is unexpectedly tripped, there is a sudden mismatch between the remaining generation and the consumer load. In order to avoid a system collapse, equilibrium must be re-established between generation and load. Automatic Load Control using frequency based load control relays is the most common form of system protection to protect against mismatches between load and generation. The allowable time to institute some control action to avoid total system collapse varies with system characteristics, but is generally extremely short.

Commonly referred to as underfrequency load shedding, Frequency Based Load Control is an extremely fast scheme that is designed to match generation with load by removing load from the utility system at discreet intervals. The frequency level and time delay associated with each load shed point is critical to the survival of the utility system.

In the HELCO system, the existing system generation allows the underfrequency relay's time delays and total tripping times to be relatively long, approximately 0.2 seconds (12 cycles) for the relays and 0.117 seconds (7 cycles) for the breakers. As steam generation is replaced with LM 2500 and wind generation, the allowable tripping time for the underfrequency system decreases to less than 0.133 seconds (8 cycles), assumed to be split between the relay, 0.050 seconds (3 cycles) and breaker 0.083 seconds (5 cycles). This is often referred to as the critical clearing time for the protection system, since clearing times exceeding a total of 8 cycles may lead to system instability.

In the existing HELCO Frequency Based Load Control system, the HELCO load shed points are comprised of 9 distinct stages of load shedding, separated by 0.2 to 0.3 Hz. The time delay is fairly long at 0.2 seconds (12 cycles) for the relay, plus 0.116 seconds (7 cycles) for the feeder breaker,

resulting in a total delay from the underfrequency detection to breaker tripping or 0.316 seconds (19 cycles). Again, this compares with a maximum allowable time delay of 0.133 seconds (8 cycles) as steam generation is displaced with either steam or wind generation.

The HELCO system is unique in generation control in that for several steam units in the system, the unit's capacity, or its highest possible output, exceeds the limit of the AGC system's control capacity. For instance, Hill 6 has a current capacity of 23 MW, however AGC can only increase the unit's capacity to 20.3 MW, 2.7 MW less than its maximum capacity. Although the difference between the maximum capacity and the AGC limit for controlled capacity may be considered a safety margin, the combination of the existing load shedding system and the limits on the AGC control place the system at risk for prolonged underfrequency operation during certain contingency conditions.

The combination of many relatively small discreet steps in a load shed scheme increases the probability of prolonged underfrequency operation as load is removed from the system in small increments. This type of scheme tends to stabilize the frequency, but not necessarily return the frequency to near 60 Hz. The "extra" spinning reserve available to the governor contributes to this off-frequency operation by driving the unit above the AGC control limit and increasing its output just enough to keep the system from shedding the next stage of load, but since the extra capacity is not under AGC control, AGC cannot return the system to 60 HZ.

In the design of the new underfrequency load shedding scheme, this "extra" spinning reserve was considered in the development of the scheme. Since this "extra" spinning reserve will help arrest frequency decay, but will not aid in returning the system to near 60 Hz, the design of the load shed system must consider this reserve in its development and implementation.

Refer to the example in figure 1 below where frequency recovery is stopped at 59.5 Hz. This frequency would continue to decay as the HEP steam unit bleeds down over the next 120 seconds. The final frequency would be achieved beyond the time limit of our studies; however, depending upon the dispatch case and the contingency, the steady-state frequency could be as low as 58.5 Hz.

Note that in the figure below, the initial frequency is 60 Hz and at the end of the simulation; the frequency has decayed to approximately 59.5 Hz. In this example, the final frequency would likely be in the 59.0 Hz range after another 100 seconds.

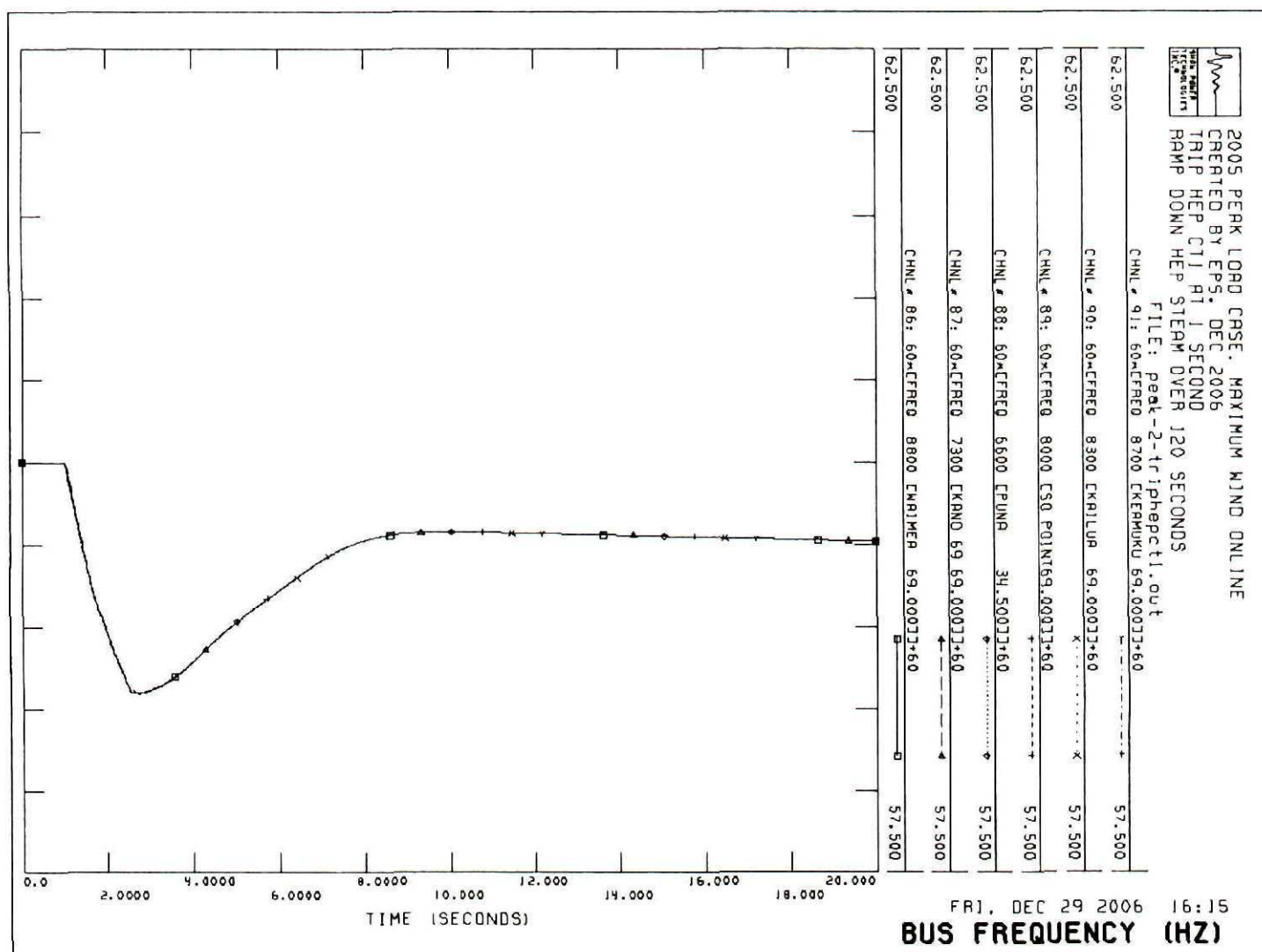


Figure 1 – Generation Trip Example – Existing Load Shed Scheme

As steam generation is displaced by LM 2500 or wind generation, the existing load shedding system results in extremely oscillatory behavior and low frequency operation following a unit trip. In some dispatch cases, the system is unstable following a unit trip and load shedding.

The purpose of an underfrequency load shed system is to protect the system from cascading blackouts or system collapse following the loss of a major unit or plant. Unnecessary consumer outages should be avoided, but not at a risk to the system as a whole.

The existing HELCO load shed scheme appears to be based on a classical load shed system found in interconnected utilities on the Mainland. The blocks are small to minimize the number of consumer outages and the total amount of load under automatic load control is only 55% of the total system load. Both of these factors may decrease the number of customers subject to particular outages, but it increases the risk of equipment damage and cascading or complete system outages during major disturbances.

We recommend the underfrequency load shed system be designed to meet the following criteria:

- Stage 1- set Stage 1 to match the output of a medium sized generator in the HELCO system. The amount of load should be selected at a nominal system value as opposed to its peak value. We recommend 15 MW of load based on a 160 MW system peak.
- Stage 2 - Set Stage 2 to match the largest single contingency plus a safety factor of 10% at the same load level. We recommend Stage 2 be set at 18 MW at a system load of 160 MW. This produces a cumulative total (stage 1 plus stage 2) of approximately 33 MW at the 160 MW load level, or approximately the amount of generation produced by HEP CT1 and ½ the HEP steam unit, plus the 10% margin.
- Stage 3 - We recommend stage 3 be set to cover the largest single contingency plus 10% at the system minimum load level. We recommend Stage 3 be set for 18 MW at a system load of 90 MW. This produces a cumulative total of approximately 33 MW at the 90 MW load level, or approximately the amount of generation produced by HEP CT1 and ½ the HEP steam unit.
- Stage 4 - We recommend stage 4 be set to cover the largest plant contingency plus 10% at the minimum system load level. We recommend Stage 4 to be set for 34 MW at a system load of 90 MW. This produces a cumulative total of approximately 66 MW at the 90 MW load level, or approximately the amount of generation produced by HEP CT1, HEP CT2 and the HEP steam unit plus 10%.

This results in a total amount of load under the automatic load control system of 150 MW at the system peak or 75% of the total system load. We believe the total amount of load under load control in the present system is deficient and does not protect the system against unforeseen contingencies such as the loss of multiple units to natural events such as earthquakes, hurricanes, etc. Plants with common control systems, such as HEP, also represent plants that can through a single contingency failure of the plant DCS, result in the loss of the entire plant output.

The design of the HELCO underfrequency load shedding system proved to be quite challenging when additional LM 2500 turbines and wind generation replace traditional steam generation. In the existing generation mix, the underfrequency system design is fairly straight-forward and can be easily implemented along the lines of the philosophy outlined above.

However, as steam units are replaced by LM 2500 units, or in the worse case wind generation, the system becomes much more unstable and extremely sensitive to the implementation of the load shedding system. For instance, the philosophy of covering a small-medium sized unit worked well at the 160 MW load level, but due to load migration between the peak and valley cases, the load shed level at the 125 MW case was approximately equal to the amount of load shed in the 160 MW case. This resulted in a slight over shed in the 125 MW case and instability in the minimum steam generation cases.

The timing of the load shed relays also becomes more critical as steam generation is reduced. The existing underfrequency tripping time or 0.317 seconds (19 cycles) is stable and well-damped in all cases where traditional dispatch is used. However, as steam generation is reduced by wind and/or LM 2500 generation, this same load shed scheme and tripping times results in large oscillations and instability for loss of generator units in the system. In order to maintain stability throughout the maximum range of dispatch cases, this tripping time must be reduced to not exceed 0.133 seconds (8 cycles).

Numerous stability cases indicated an extreme system frequency reaction when too much or too little load is shed for various generation trip cases, when all or most traditional steam generation was replaced by wind and or LM 2500 generation. The load shedding scheme was adjusted to try to minimize the possibility of inappropriate amounts of load shedding during unit trip scenarios.

In addition to this change, a backup stage of underfrequency load shedding was added to remove 4 MW of load (as measured in the valley case) at 59.3 Hz with an extended time delay of 20 seconds.

This 4 MW load level should consist of load that is also included in either stage 3 or stage 4 of the load shedding schedule. The last “kicker” block of load helps avoid prolonged operation at underfrequency conditions.

The proposed schedule also has considerably more load under control to cover against unforeseen contingencies such as earthquakes, bus outages, hurricanes, etc. that may force more than the largest contingency off-line. This is important as it does not appear the existing loadshedding schedule can cover the loss of the multiple units without total system collapse or extremely fast manual intervention. In developing the loadshedding schedule, we considered the possibility of a HEP DCS failure could result in the tripping or unloading of the entire HEP plant as the largest design condition for plant contingencies. Although other contingencies may also produce this loss of generation, we believe this design level will provide good protection for the HELCO system.

The existing HELCO load shedding settings and the EPS proposed settings are shown in table 6 below:

Table 6 – Load Shed Settings

Load Case		Existing HELCO Load Shed Settings										EPS Load Shed Settings				
		59.0	58.8	58.6	58.4	58.2	58.0	57.8	58.5	57.0		58.8	58.5	58.0	57.7	59.3
Peak	this stage	1.0	14.4	11.1	9.8	14.6	8.0	11.1	22.0	14.1		18.3	21.3	44.8	58.5	6.7
	cumulative	1.0	15.4	26.5	36.3	50.9	58.9	70.0	92.0	106.1		18.3	39.6	84.4	142.9	142.9
160 MW	this stage	0.9	12.0	9.4	8.3	12.2	6.7	9.3	18.4	11.8		15.3	17.9	37.5	49.0	5.5
	cumulative	0.9	12.9	22.3	30.6	42.8	49.5	58.8	77.2	89.0		15.3	33.2	70.7	119.7	119.7
125 MW	this stage	4.7	8.1	5.2	5.5	7.3	4.0	6.3	16.5	12.9		9.5	11.5	24.4	45.8	5.0
	cumulative	4.7	12.8	18.0	23.5	30.8	34.8	41.1	57.6	70.5		9.5	21.0	45.4	91.2	91.2
Valley	this stage	3.4	5.8	3.7	4.0	5.3	3.0	4.6	11.9	9.3		6.8	8.4	17.8	33.2	3.6
	cumulative	3.4	9.2	12.9	16.9	22.2	25.2	29.8	41.7	51.0		6.8	15.2	33.0	66.2	66.2
Tripping Time	(seconds)	0.317	0.317	0.317	0.317	0.317	0.317	0.317	2.5,10	0		0.133	0.133	0.133	0.133	20

To illustrate the above point, figure 2 below is a 30 MW unit trip (21.5 MW HEP CT1 trip followed by a 8.5 MW ramp down of the steam unit over 120 seconds) for a traditional dispatch using the existing HELCO load shedding scheme at a system load level of 160 MW.

Note that in the simulation below, system frequency is initially set at 60 Hz. At 1 second in the simulation, the HEP unit is tripped, frequency dips to 58.4 Hz, shedding four stages of loadshedding in the existing HELCO scheme and frequency returns to 60 Hz.

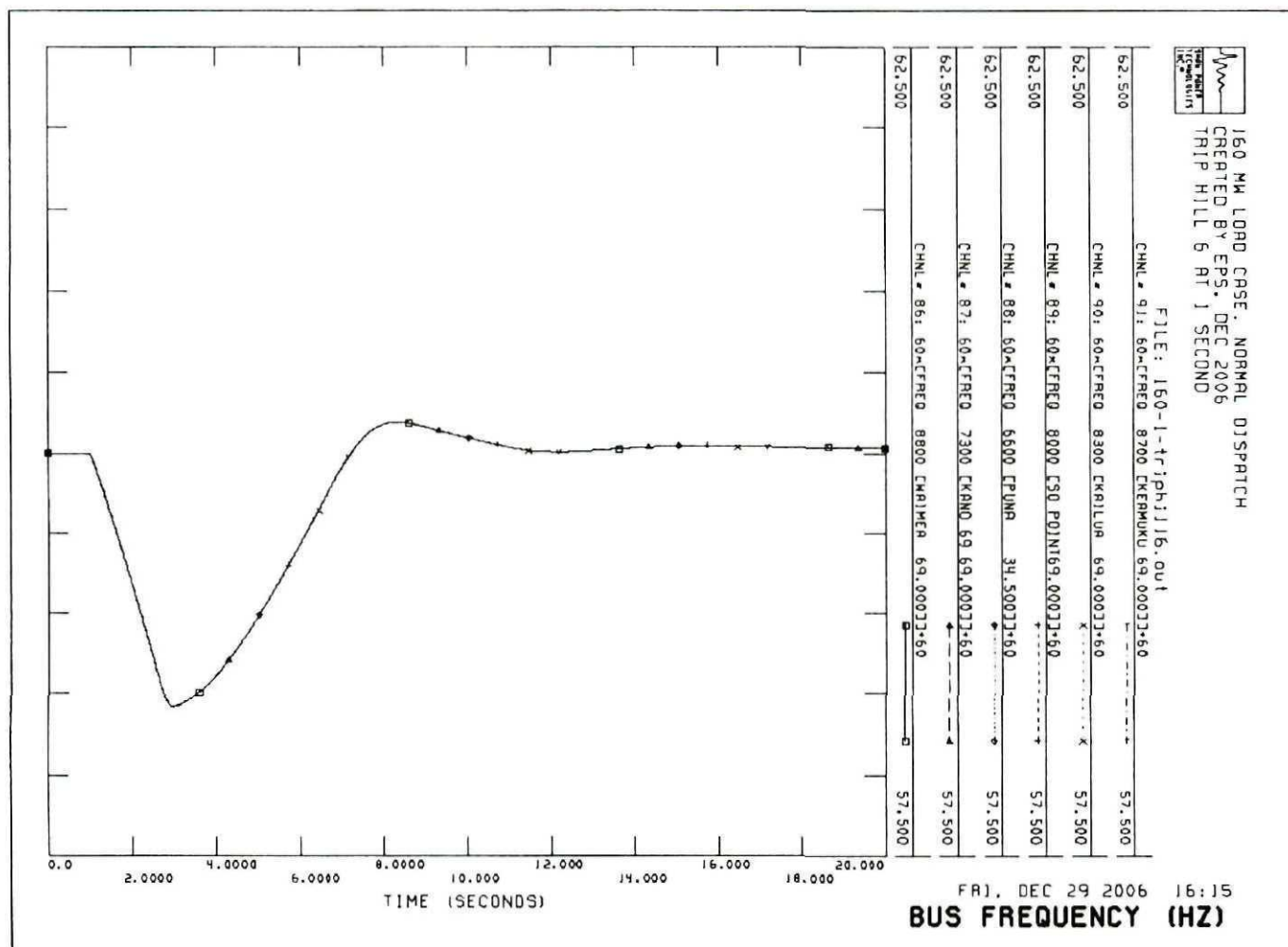


Figure 2 – Hill 6 Trip at 160 MW – Existing HELCO Load Shed Settings

For the same load level, figure 3 below represents the system response to the same contingency when Hill 5 and Puna steam are displaced by 30 MW of wind generation. (complete stability files are included in the appendix).

In this simulation, the initial frequency is set to 60 Hz and the HEP unit is tripped at 1 second. Frequency dips to 58.3 Hz and sheds four levels of HELCO load shed. However in this case, the backswing overfrequency reaches 61.6 Hz and creates prolonged oscillations in the system. Although stable, the oscillations are only slightly damped and are present in the system for an extended time (well beyond 120 seconds).

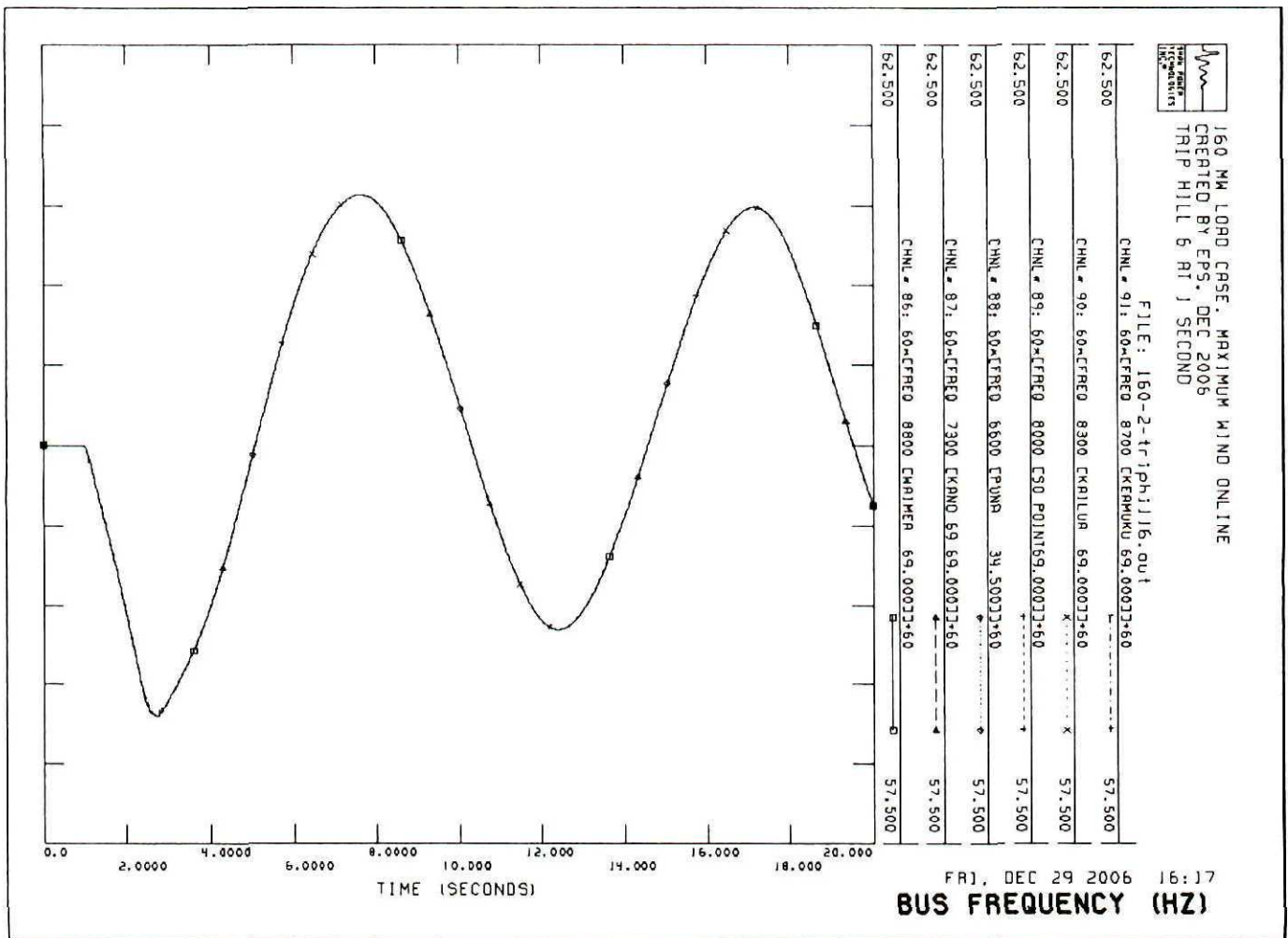


Figure 3 – Hill 6 Trip at 160 MW – Steam Displaced Existing Loadshed

For the same two contingencies, the modified load shed scheme results in the following simulated response using the proposed loadshedding schedule:

Note that in Figure 4, the initial frequency is set to 60 Hz and the HEP unit is tripped at 1 second. The lowest frequency is 58.7 Hz and the system returns to 60 Hz following loadshedding.



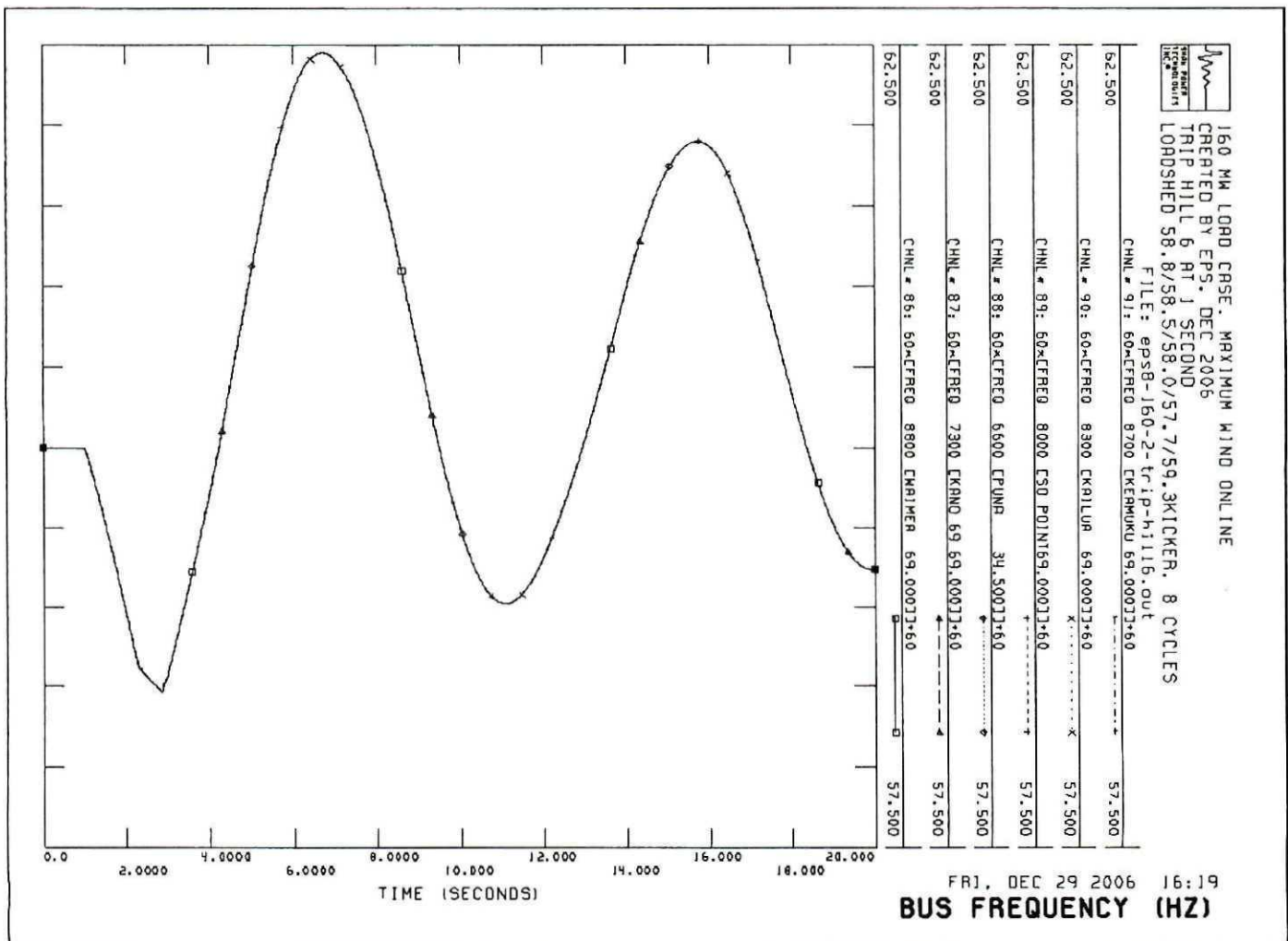


Figure 5 – Hill 6 Trip – Displaced Steam – EPS Load Shed Settings

The simulations above show that the existing load shed scheme results in good response for the traditional dispatch case, but oscillatory and unstable response when 30 MW of wind displaces the Hill 5 and Puna steam units. The proposed EPS load shed scheme also works well in the traditional dispatch case, and although the maximum wind case results in oscillatory behavior, it is damped and stable.

In all unit trip and line outage simulations, the system becomes extremely oscillatory as steam units are displaced with wind generation and/ or LM 2500 units. When all steam units are removed from operation, the system becomes unstable and extremely oscillatory for many minor disturbances such as line outages and unit trips. For this reason we would recommend the system not be operated with less than two steam units on-line at any time.

For each of the four load levels, EPS simulated the loss of various generators under each of the dispatch scenarios. The simulations were used to evaluate the response of the system to a single-contingency loss of generation. A description of each of the scenarios is presented in the tables below. Table 7-1 represents the system using the existing HELCO load shedding scheme for each

of the evaluated scenarios. Table 7-2 represents the results of the system simulation using the load shedding schedule proposed by EPS.

Table 7-1 – Generation Trip Results – HELCO Load Shed

Load Case	Generation Trip		Dispatch Case			
			Actual	Max Wind	Max LM 2500 min wind	Max Wind/ LM 2500(min steam)
Peak	Hill 6	Min Hz	58.7	58.7	58.4	
		Notes	stable, smooth	stable	stable, damped	
	CT3	Min Hz	58.7			
		Notes	stable, smooth			
	CT5	Min Hz			58.4	
		Notes			stable, damped	
	HEP CT1	Min Hz	58.7 Hz	58.7		58.4
		Notes	stable, smooth	stable		damped
	Hill 5	Min Hz				58.7
		Notes				unstable
160 MW	Hill 6	Min Hz	58.4	58.3		
		Notes	well damped	poorly damped		
	CT5	Min Hz	58.4	58.4		58.4
		Notes	well damped	unstable		poorly damped
	HEP CT1	Min Hz		58.3		58.2
		Notes		unstable		poorly damped,
125 MW	Hill 6	Min Hz	58.4		58.35	
		Notes	well damped		well damped	
	Hill 5	Min Hz		58.6		
		Notes		well damped		
	CT3	Min Hz			58.6	58.5
		Notes			smooth ramp	oscillatory, damped
	HEP CT1	Min Hz	58.5	58.2		58.2
		Notes	damped, return to 59.5	well damped		oscillatory, damped
Valley	Hill 6	Min Hz	58.3			
		Notes	well damped			
	Puna Steam	Min Hz	58.7			
		Notes	damped, return to 59.7			
	Hep CT 1	Min Hz				unstable
		Notes				system collapse
Existing HELCO Loadshedding Scheme						

Table 7-2 – Generation Trip Results – EPS Load Shed

Load Case	Generation Trip		Dispatch Case			
			Actual	Max Wind	Max LM 2500 min wind	Max Wind/ LM 2500(min steam)
Peak	Hill 6	Min Hz	58.7	58.7	58.7	
		Notes	stable, smooth	stable	damped	
	CT3	Min Hz	58.7			
		Notes	stable, smooth			
	CT5	Min Hz			58.7	
		Notes			damped	
	HEP CT1	Min Hz	58.7 Hz	58.7		58.7
		Notes	stable, smooth	stable		damped
160 MW	Hill 6	Min Hz	58.6	58.5		
		Notes	well damped	overswing to 62.5 Hz, stable		
	CT5	Min Hz	58.6	58.7		58.7
		Notes	well damped	smooth ramp		well damped
	HEP CT1	Min Hz				58.4
		Notes				poorly damped, 2.2 Hz overswing oscillatory for extended period
	Hill 6	Min Hz	58.4		58.35	
		Notes	well damped		well damped	
125 MW	Hill 5	Min Hz		58.5		
		Notes		well damped		
	CT3	Min Hz			58.7	58.5
		Notes			smooth ramp	oscillatory, damped
	HEP CT1	Min Hz	58.5	58.3		58.3
		Notes	damped	uses kicker block		oscillatory, damped
	Hill 6	Min Hz	58.4			
		Notes	well damped			
Valley	Puna Steam	Min Hz	58.4			
		Notes	well damped			
	Hep CT 1	Min Hz				unstable
		Notes				system collapse
EPS Proposed Loadshedding Schedule						

Comparing tables 7-1 and 7-2, in the typical dispatch scenarios, there is little difference in the minimum frequency between the existing and proposed load shedding cases. In some cases of the existing load shedding schedule, the frequency does not return to 60 Hz, but hovers in the 59.0 – 59.5 range. This type of control is undesirable due to the impact the low frequency operation has on steam turbines in particular and the increased risk of subsequent unit trips during the event.

As the dispatch cases deviate from the historic or traditional mix of generation, the differences between the proposed and existing load shed begin to grow. The proposed load shed scheme has a more robust response range and frequency control characteristics than the existing load shed schedule, returning the system to 60 Hz in a stable solution in all but the most severe dispatch case.

6 Transient Stability Simulations – Line Fault Conditions

EPS conducted transient stability simulations for various 69 kV transmission line fault scenarios, under each of the load levels and dispatch cases utilized for the underfrequency load shedding studies. These are discussed below.

6.1 69 kV Line Fault Scenarios

Simulations were run for nine 69 kV line faults, representing several critical lines throughout the HELCO system. A fault clearing time based on the type of breaker and the location of the fault was determined from discussion with HELCO. The clearing times varied from 4 cycles for a near end fault with an SF6 breaker, to 7 cycles for a far end fault with an oil breaker. Table 8 below lists the line fault scenarios studied. Each line outage was evaluated with the fault first at one end of the line, and then again with the fault at the opposite end. Each outage was studied with each of the 13 different dispatch scenarios.

Table 8 – 69 kV Line Fault Cases

Line #	Location
6200	Kaumana-Keamuku
6300	Puna-Kilauea
6600	Kilauea-Kealia
7200	Keamuku-Waimea
7700	Haina-Waimea
8500	Keamuku-Kaumana
8600	Kealia-Kahaluu
8800	Haina-Honokaa
9100	Keahole-Kailua

Table 9-1 thru 9-4 below summarizes the 69 kV line fault cases. Transient stability simulation plots are included in the appendix for each case.

The line outage cases were all run with the existing HELCO load shedding scheme in place. Some load shedding does occur in a few outage cases.

The line 6600 cases were run in two different scenarios. For those cases with no Apollo wind farm generation, line 6600 was assumed to be configured as presently exists, with no new substation at the Apollo interconnection. Therefore, in these cases, line 6600 is faulted once at the Kilauea end and then once at the Kealia end. When the Apollo wind farm exists and is online in the power flow case, line 6600 is modeled with the new breakers in place on the 69 kV line at the interconnection point. Line 6600 is then divided into two new lines. These have been designated line 6600-east and 6600-west in the stability runs. In these cases, the line fault is always assumed to be at the Apollo end of the line, but when the line fault is cleared, the wind farm remains connected to the remaining in service line.

Most of the line fault simulations were run for 10 seconds. However, a few of the cases showed larger oscillations and possible undamped response when run for 10 seconds. These cases were run longer to better assess the overall system response.

Table 9-1 – 69 kV Line Fault Case Results – Peak Load

		Peak Load Cases			
		Historic Dispatch (Peak-1)	Max Wind (Peak-2)	Max LM 2500/ Min Wind (Peak-3)	Max Wind & LM2500/ Min Steam (Peak-4)
Line Outage	6200	minor oscillation, min 59.6 Hz	more overspeed, slight oscillations	larger oscillations, stable	larger oscillations, stable
	6300	minor oscillation, min 59.7 Hz	minor disturbance	minor disturbance	minor disturbance
	6600	minor disturbance	minor disturbance	minor disturbance	minor disturbance
	7200	slight inter-unit oscillations, min 59.6 Hz	minor disturbance	slight inter-unit oscillations, min 59.5 Hz	larger oscillations, stable
	7700	inter-unit oscillations, min 58.8 Hz	slight inter-unit oscillations, min 59.3 Hz	large inter-unit oscillations, min 58.7 Hz, 1st stage LS	larger oscillations, stable, 1st stage LS
	8500	slight inter-unit oscillations, min 59.6 Hz	minor disturbance	slight inter-unit oscillations, min 59.5 Hz	larger oscillations, stable
	8600	minor disturbance	minor disturbance	minor disturbance	minor disturbance
	8800	slight inter-unit oscillations, min 59.4 Hz	slight inter-unit oscillations, min 59.4 Hz	slight inter-unit oscillations, min 59.3 Hz	larger oscillations, stable
	9100	slight inter-unit oscillations, min 59.2 Hz	minor disturbance, min 59.4 Hz	1st stage LS, stable	1st stage LS, lightly damped

Table 9-2 – 69 kV Line Fault Case Results – 160 MW Load

		160 MW Load Cases		
		Historic Dispatch (160-1)	Max Wind (160-2)	Max Wind/ LM 2500/ Min Steam (160-3)
Line Outage	6200	minor oscillation, min 59.6 Hz	more overspeed, slight oscillations	sustained long-term oscillations +/- 0.5 Hz
	6300	minor oscillation, min 59.7 Hz	minor disturbance	minor disturbance
	6600	minor disturbance	minor disturbance	stable - but long-term oscillations +/- 0.3 Hz
	7200	slight inter-unit oscillations, min 59.5 Hz	minor disturbance	sustained long-term oscillations +/- 0.5 Hz
	7700	inter-unit oscillations, min 58.8 Hz	slight inter-unit oscillations, min 59.2 Hz	sustained large oscillations +/- 1.0 Hz
	8500	slight inter-unit oscillations, min 59.6 Hz	minor disturbance	sustained long-term oscillations +/- 0.3 Hz
	8600	minor disturbance	minor disturbance	minor disturbance
	8800	slight inter-unit oscillations, min 59.4 Hz	slight inter-unit oscillations, min 59.7 Hz	inter-unit oscillations, min 58.7 Hz; lightly damped
	9100	slight inter-unit oscillations, min 59.4 Hz	minor disturbance, min 59.4 Hz	inter-unit oscillations, min 58.7 Hz; undamped

Table 9-3 – 69 kV Line Fault Case Results – 125 MW Load

		125 MW Load Cases			
		Historic Dispatch (125-1)	Max LM2500/Min wind (125-2)	Max Wind/ Min LM 2500 (125-3)	Max Wind/ Max LM2500/ No Steam (125-4)
Line Outage	6200	overspeed to 61 Hz, stable	overspeed to 60.7 Hz, stable	overspeed to 60.7 Hz, stable	sustained long term oscillations 0.2 Hz
	6300	overspeed to 60.6 Hz, stable	overspeed to 60.7 Hz, stable	overspeed to 60.5 Hz, stable	sustained long term oscillations 0.3 Hz
	6600	minor disturbance	minor disturbance	1st stage load shed, stable	sustained long term oscillations 0.2 Hz
	7200	overspeed to 60.6 Hz, stable	minor disturbance	minor disturbance	sustained long term oscillations 0.2 Hz
	7700	overspeed to 61 Hz, stable	overspeed to 61.3 Hz, stable	overspeed to 60.6 Hz, stable	sustained long term oscillations 0.2 Hz
	8500	overspeed to 60.6 Hz, stable	overspeed to 60.6 Hz, stable	overspeed to 60.6 Hz, stable	sustained long term oscillations 0.2 Hz
	8600	overspeed to 60.5 Hz, stable	minor disturbance	minor disturbance	sustained long term oscillations 0.2 Hz
	8800	overspeed to 60.6 Hz, stable	overspeed to 60.6 Hz, stable	overspeed to 60.5 Hz, stable	larger oscillations, damped
	9100	overspeed to 60.4 Hz, stable	overspeed to 60.4 Hz, stable	minor disturbance	sustained long term oscillations 0.2 Hz

Table 9-4 – 69 kV Line Fault Case Results – Valley Load

		Valley Load Cases	
		Historic Dispatch (Valley-1)	Max Wind/ Max LM 2500/ No Steam (Valley-2)
Line Outage	6200	overspeed to 61 Hz, stable	overspeed to 60.6 Hz, stable
	6300	overspeed to 60.6 Hz, stable	overspeed to 60.6 Hz, stable
	6600	minor disturbance	1st stage LS, stable
	7200	overspeed to 60.5 Hz, stable	minor disturbance
	7700	overspeed to 60.5 Hz, stable	minor disturbance
	8500	overspeed to 60.7 Hz, stable	minor disturbance
	8600	overspeed to 60.3 Hz, stable	minor disturbance
	8800	overspeed to 60.6 Hz, stable	minor disturbance
	9100	overspeed to 60.4 Hz, stable	overspeed to 60.3 Hz, stable

The line outage results clearly show a tendency for sustained oscillations or poorly damped response in those cases where steam based generation is replaced with wind and or LM 2500 based generation. Power flow cases peak-4, 160-3, and 125-4 are cases with maximum wind and maximum LM 2500s online, and these cases show a clear decrease in system response performance as compared to the nominal cases with present day dispatch scenarios.

7 Transient Stability Results – Wind Variation Effects

The effect of wind power variation was studied by running transient stability cases with a time varying load placed at the Apollo wind farm site. The load was increased at a rate of 0.1 MW/second for 12 seconds, and then ramped back down to zero at the twice the rate for 12 seconds. This corresponds to a rate of 6 MW / minute down and 12 MW/ minute up. These rates were chosen to represent the maximum ramp rate of wind generation in one direction and the additive ramp rate of wind generation and AGC in the other direction.

These cases reflect a slow speed variation in wind power, not a high speed, abrupt power swing. The stability simulations should be used as a method of evaluating the impact changes in wind

generation has on the ability of the system to maintain steady-state frequency control. The exact magnitude of the frequency variation to be expected due to wind variation can be very difficult to compute due to the response of system governors and AGC. This is especially true due to the inherent deadband and sluggish response of speed governors to small scale frequency variations and the interaction between AGC and wind generation.

The interaction between wind generation, AGC and thermal generation governors is virtually impossible to predict using transient stability simulations. The response frequency of AGC and wind generation may be in-synch at some times resulting in minor deviations, or they may be timed such that AGC control adds to the frequency deviation of wind, resulting in excessive frequency deviations.

Table 10 lists the maximum frequency variation and notes for each of the 13 cases. In each case, the effective wind power output is reduced by 1.2 MW and then ramped back up to the pre-disturbance value.

Table 10 – Wind Variation Effects

Dispatch Case	Wind Power (MW)	Freq Variation (Hz)
Peak-2	30	0.025
Peak-4	30	0.035, small oscillations
160-2	30	0.04
160-3	30	0.08, extreme oscillations
125-3	30	0.06
125-4	20	0.09, extreme oscillations
Valley-1	2.4	0.055
Valley-2	30	0.13

The stability results show two dominant trends. First, the magnitude of the frequency excursion gets bigger as the load level is reduced and the online thermal generation, particularly steam generation is reduced. Second, the same dispatch scenarios that showed oscillation problems and lightly damped response for the line faults and unit trips also show oscillations when exposed to normal wind power variations.

These studies should not be used to predict the actual frequency deviations in any dispatch or load scenario, but can be used to provide an understanding of how frequency control is impacted by wind generation. The trend toward more oscillatory frequency control in simulations will most likely be magnified in the actual system control when AGC and normal load changes interact with the variation in wind generation.

CERTIFICATE OF SERVICE

The foregoing HECO Companies' Submission of Supplemental Information was served on the date of filing by mail, postage prepaid, and properly addressed or electronically transmitted to each such Party.

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